Service Date: May 9, 2001

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

IN THE MATTER of the Application of	)	UTILITY DIVISION
the MONTANA POWER COMPANY for	)	
Authority to Increase Rates for Electric	)	DOCKET NO. D2000.8.113
and Gas Service	)	FINAL ORDER NO. 6271c
	)	(REVENUE REQUIREMENT)
	)	

* * * * *

FINAL ORDER

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APPEARANCES

FOR THE APPLICANT:

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FOR THE COMMISSION:

Eric N. Eck, Chief Revenue Requirements Bureau
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BEFORE:

Gary Feland, Chairman
Jay Stovall, Vice Chairman
Bob Anderson, Commissioner
Matt Brainard, Commissioner
Bob Rowe, Commissioner

BACKGROUND

1. Montana Power Company (MPC) filed an application for a general rate case for its regulated gas and electric utilities on August 11, 2000. The application was assigned Docket D2000.8.113. The filing requested an increase in electric annual revenues of $38,504,998, a uniform percentage increase of 21.2 percent in delivery rates for all Montana jurisdictional electric customers. MPC requested an increase in natural gas revenues of $12,010,585, a uniform percentage increase of 14.3 percent in delivery and storage rates for natural gas customers. MPC's filing was based on a calendar 1999 test period.

2. Intervenors in this Docket were the Montana Consumer Counsel (MCC) with testimony and exhibits from Albert E. Clark and Steven G. Hill, the Large Customer Group (LCG) with testimony from Alan E. Rosenberg, Colstrip Energy Limited Partnership, Cut Bank Gas Company, Jefferson Energy Trading, LLC, Montana Department of Natural Resources and Conservation, Yellowstone Energy Limited Partnership, American Association of Retired Persons, Commercial Energy of Montana, and District XI Human Resource Council. Numerous consumers expressed opposition to the rate increase request.

3. Concurrent with its general rate increase application, MPC requested an interim increase in electric revenues of $24,966,212. The electric interim request represented a uniform percentage increase of 13.8 percent. MPC requested an interim increase in natural gas revenues of $5,997,425. The natural gas interim request represented a uniform percentage increase of 7.16 percent.

4. On November 28, 2000, the Commission, by a 4-1 vote, granted interim rate relief in the amount of $14,525,959 for the regulated electric utility and $5,277,978 for the regulated natural gas utility. The interim increase was applied uniformly to all customer classes.

5. MPC based both the final and interim rate increase requests for the electric and natural gas utilities on the Commission's former optional filing rules. Those rules expired prior to the filing of this application. MPC also presented for informational purposes, filing information under the Commission's traditional filing rules. The interim rate relief was granted on the basis of the traditional filing rules.

6. The requested electric interim increase was based on an overall rate of return of 8.83 percent on rate base and a cost of common equity of 11.0 percent. The requested gas interim

increase was based on an overall rate of return of 9.19 percent and a cost of common equity of 11.25 percent. The electric rate of return was approved in Docket No. D95.9.128 and the gas rate of return was approved in Docket No. D96.2.22.

7. In its filing MPC noted that the Company had offered a Special Retirement Plan (SRP) to employees 50 years-of-age and older with at least five years of service, but the results of the employees' decisions were not known at the time the filing was made. MPC indicated that this reduction in expenses would be provided as soon as it became available so that the reduction could be incorporated into the interim process. On October 3, 2000, MPC filed a letter on the SRP, which provided for decreases in revenue requirements for both the electric and gas utilities.

8. On January 30 and 31, 2001, a hearing in this Docket was held.

9. On February 26, 2001, initial briefs were filed by MPC, MCC and the LCG.

10. On March 14, reply briefs were filed by MPC, MCC and the LCG.

FINDINGS OF FACT AND ANALYSIS

Rate of Return

Capital Structure

11. Ms. Senechal, a witness for MPC, stated that the beginning point in determining the Montana jurisdictional electric and gas utility capital structure is MPC's consolidated capitalization at March 31, 2000, adjusted for known and measurable changes. Ms. Senechal adjusted the capitalization to remove Entech and miscellaneous investments. Long-term debt was reduced to exclude debt due in one year. Of the total utility capital, 75.1 percent of the capitalization was allocated to the electrical utility, the gas utility was allocated 24.8 percent and the propane utility, 0.1 percent. She stated the allocation factor was based on the ratio of the electric, natural gas and propane utility rate base to the total utility rate base at March 31, 2000, plus construction work in progress at March 31, 2000.

12. Ms. Senechal stated that the capital structure debt proportions were roughly the same before and after the generation sale. She stated that for both the electric and gas utility, capital structure proposed was 36.65 percent long-term debt, 7.86 percent QUIPS Preferred, 6.97 percent preferred stock and 48.52 percent common equity.

13. MPC proposed the following capital structure and associated costs for the electric utility:

Type of Capital	Amount	Percent Capitalization	Rate	Rate of Return
Long Term Debt	$227,553	36.65%	6.46%	2.37%
QUIPS	48,815	7.86%	8.54%	0.67%
Preferred Stock	43,298	6.97%	6.40%	0.45%
Common Equity	301,277	48.52%	12.75%	6.19%
	$620,943	100.00%		9.68%

14. MPC proposed the following capital structure and associated costs for the gas utility:

Type of Capital	Amount	Percent Capitalization	Rate	Rate of Return
Long Term Debt	$75,144	36.65%	7.13%	2.61%
QUIPS	16,120	7.86%	8.54%	0.67%
Preferred Stock	14,298	6.97%	6.40%	0.45%
Common Equity	99,490	48.52%	13.50%	6.55%
	$205,052	100.00%		10.28%

15. Mr. Hill, representing MCC, recommended for ratemaking purposes, a capital structure target for gas distribution operations of 45 percent common equity, similar to industrial averages. Mr. Hill recommended for the electrical transmission and distribution operations (T&D), an equity ratio of 40 percent. MPC indicated the electrical T&D operations were capitalized at $621 Million.

16. MCC adjusted the common stock equity to 40 percent and kept QUIPS and preferred stock constant at the level requested by the company. This resulted in a capital structure for MPC of 40 percent common stock, 6.97 percent preferred stock, 7.86 percent QUIPS, and 45.17 percent long-term debt for the electric debt structure. MCC used the same assumptions and a 45 percent equity ratio for the gas utility, which resulted in a capital structure of 45 percent common, 6.97 percent preferred, 7.86 percent QUIPS and 40.17 percent long-term debt.

17. MCC recommended the following capital structure and associated costs for the electric utility:

Type of Capital	Amount	Percent Capitalization	Rate	Rate of Return
Long Term Debt	$280,453	45.17%	6.46%	2.92%
QUIPS	48,815	7.86%	8.54%	0.67%
Preferred Stock	43,298	6.97%	6.40%	0.45%
Common Equity	248,377	40.00%	10.25%	4.10%
	$620,943	100.00%		8.14%

18. MCC recommended the following capital structure and associated costs for the gas utility:

Type of Capital	Amount	Percent Capitalization	Rate	Rate of Return
Long Term Debt	$82,361	40.17%	7.13%	2.86%
QUIPS	16,120	7.86%	8.54%	0.67%
Preferred Stock	14,298	6.97%	6.40%	0.45%
Common Equity	92,273	45.00%	10.75%	4.84%
	$205,052	100.00%		8.82%

19. Mr. Hill, in his direct testimony for the MCC, took exception to MPC's proposed capital structure. He stated the proposed capital structure was not similar to how MPC had been capitalized over the past few years. He accepted the 7.86 percent QUIPS and 6.97 percent preferred stock proposed by MPC. He stated that MPC had been capitalized on average over the past three years with a 42 percent common equity, 10 percent preferred stock and securities, and 48 percent long-term debt. He also stated that in Docket No. D99.8.176, MPC's gas case last year, that the proposed MPC capital/debt structure was 43.94 percent common equity, 9.97 percent preferred stock and securities, and 46.10 percent long-term debt.

20. Mr. Hill stated that the shift in mix of the capital structure was brought about by the sale of the generation facilities. He took exception to Ms. Senechal's testimony that MPC had maintained roughly the same proportions of debt and common equity in the capital structure before and after applying the proceeds of the sale of generation assets. MPC, with the proceeds from the sale repurchased $264.7 of its long-term debt and $144.8 of its common equity. That shifted the equity ratio from 42 percent to 48.5 percent and shifted the debt ratio from 48 percent

to 36.5 percent. Mr. Hill contended those changes were not "roughly" the same as was claimed by Ms. Senechal.

21. Mr. Hill noted that the generation assets of an electric utility operation are its most risky assets, therefore those assets are the primary source of operational risk of an electric utility operation. He said that with regard to MPC's capital structure shift, that it should be noted that a fully-integrated MPC--the company *with* generation assets was effectively capitalized at 42 percent common equity for several years. He commented that the action by MPC ran counter to the fundamental financial tenet that a lower risk firm can be more cost-effectively capitalized with more debt and less equity that a higher-risk firm. Mr. Hill stated that MPC had lowered its risk by selling the generation facilities and yet wanted its ratepayers to pay rates based on a capital structure appropriate for a riskier enterprise.

22. Mr. Hill stated that the dollar impact on ratepayers of the MPC capital structure shift using MPC's requested capital cost rates and comparing the pre-tax cost of capital produced by its requested capital structure would be more than $10 million per year.

23. Mr. Hill stated that Value Line, C.A. Turner's and Edward Jones, three different investor publications, stated the common equity ratio average for gas distribution companies is 45 percent of total capital. Mr. Hill said that current industry equity ratio averages were 40 percent for electric utilities and 38 percent for combination electric and gas utilities. Those indicators, contended Mr. Hill, are important in this proceeding given that Ms. Senechal showed that 75 percent of MPC's total utility investment was electrical T&D operations and the gas utility was 25 percent. Mr. Hill went on to comment that T&D utilities are considered less risky than fully integrated electrical companies and that his view was supported by bond rating agencies. He quoted a September 1998 Standard and Poor's article that stated:

> "Owing to the relatively low business risk of large transmission systems and regulated distribution systems (the "wires" business) business profile assessments in this area should fall within the 1-4 [Low Risk] range."

24. Mr. Hill remarked that in October 1999, Standard and Poor's reiterated its position and that the republishing of its position a year later, while restructuring has progressed, demonstrated that it was Standard and Poor's view that transmission and distribution operations are expected to exhibit lower risk profiles than fully-integrated electrical operations.

25. Mr. Hill stated that another major bond rating agency, Moody's Investor Services, while cautioning its subscribers that electrical distribution companies' credit profiles will vary depending on the circumstances of each company recognized, as a general matter, that transmission and distribution operations will have a lower risk profile than fully integrated electric utilities.

26. Mr. Hill also stated that another bond rating agency, Duff & Phelps, in its "Special Report, the Electric Utility Industry, Credit Quality Implications of Electric Industry Disaggregation" of October 1996 commented that "In general, it is reasonable to expect that within a given rating category companies involved in only the distribution and transmission segments of the electric utility business will have a lower risk profile."

27. Mr. Hill stated that the bond rating agencies have quantified the level of debt leverage expected with electric T&D companies. He went on to state that both Moody's and Standard and Poor's believe that electric distribution operations are expected to be capitalized with more leverage (more debt and less equity) than fully integrated companies. Standard and Poor's recently published Infrastructure Finance article regarding bond rating methodology for power companies worldwide stated that the median debt to capital ratio for A and BBB rated fully-integrated electric operations ranges from 45 to 56 percent whereas for T&D operations median debt to capital ratios of 55 to 65 percent for A and BBB rated companies respectively. Moody's, in its October 1997 Special Comment, confirmed Standard and Poor's projections.

28. Mr. Rosenberg, of the LCG, also took exception to MPC's proposed capital structure. He stated that the proposed capital structure was not reasonable for a T&D utility. He stated that common equity was the most expensive form of capital and that the return on common equity was subject to income tax expense. He also stated that debt was a lower cost form of capital and interest was not part of the utility's taxable income. He stated that the risk associated with a T&D company was generally considered lower than a company that also has generation. A T&D company has a greater stability and predictability of revenues and cash flow since they are not subject to energy supply price risks. Consequently, a T&D can support greater leverage than distributors with substantial commodity price risk.

29. Mr. Rosenberg recommended that the Commission provide a least cost capital structure that would adequately maintain the utility's credit quality and financial integrity. He

reemphasized that MPC's proposal for a capital structure with long-term debt of less that 40 percent would not provide a least cost capital structure and should be rejected.

30. Ms. Senechal, in rebuttal, restated her exhibit. The revisions were made to reflect the changes made by Mr. Benore in his rebuttal testimony with respect to the comparable companies for the electric utility. Ms. Senechal stated that MPC purchased approximately $265 million of outstanding debt and $145 million of outstanding equity with the proceeds from the generation sale. An additional $99 million was used to reduce the equity in the utility by investing the proceeds as a capital infusion into MPC's non-utility operations.

31. In MPC's initial brief, the Company requested the Commission to allow it to earn on a capital structure that was made up of at least as much equity as before the generation sale and more in the near term until the changes in the electric industry are resolved.

32. In MCC's initial brief, MCC stated that MPC's electric transmission and distribution (T&D) operations had a lower business risk that its fully-integrated operations and that an appropriate rate making capital structure should have a lower equity ratio than MPC had, on average, over the past few years.

33. In the LCG initial brief, the LCG also recommended to the Commission a least cost capital structure that would be more appropriate to a T&D utility, such as MPC has become. The LCG stated that a debt ratio of between 55 percent and 65 percent was appropriate for a T&D utility.

34. Both MPC's concern about regulatory risk necessitating a more equity weighted capital structure and MCC's least cost capital structure are valid concerns and arguments. MPC used the proceeds of the sale of generation assets to reduce both the debt and equity of the company and strengthen its equity position going into an uncertain future. MCC stated that MPC should have used the proceeds of the generation sale to buy down the equity, because equity is a more expensive form of financing and that MPC should use a least cost capital structure. Both arguments have merit and are given consideration by the Commission.

35. In Docket No. 93.6.24, both MCC and MPC agreed to and the Commission accepted a regulatory capital structure that had a 44.12 percent common equity component for both the gas and electric utilities. This was prior to the divestiture of the more risky electrical generation facilities.

36. MCC recommended the ideal equity structure based on 40 percent common stock for electrical T&D. MPC requested a 48.52 common stock based equity structure. Standard and Poor's capital structure was from 45 to 55 percent for A to BBB rated T&D companies, respectively. Given this, MCC's recommended capital structure may be inadequate to assure capital strength of the electric utility, but MPC's requested 48.52 percent creates an undue excess of equity in the capital structure given the less risky T&D organization that MPC has become. MPC gave no supporting evidence that it has been turned down for any financing that it has wished to obtain. MPC had, until the sale of the more risky generation facilities, an authorized regulated capital structure with 44.12 percent common equity. The Commission determines that a 43 percent equity ratio will be sufficient to ensure MPC's financial integrity.

37. MCC recommended a capital structure based on 45 percent common stock for the gas utility. MPC requested the identical 48.52 percent common stock based equity structure that it had for the electrical utility. As a result of deregulation, MPC's gas operations now consist of T&D facilities. In fact, supply risk is now borne by the ratepayers. Supply costs are recovered through MPC's annual gas tracker. Given the deregulation of supply, the Commission finds that the appropriate equity ratio for the natural gas utility is 45 percent.

Cost of Capital

38. MPC proposed a rate of return on common equity of 13 percent for the electric utility and 13.5 percent for the natural gas utility. Mr. Benore, representing MPC, in rebuttal testimony, lowered his estimated cost of capital for the electrical utility to 12.75 percent from the originally submitted 13 percent. Mr. Benore stated that the cost of capital adjustment was because two of his selected narrow criteria companies were no longer comparable risk companies. Ms. Senechal and Mr. Benore provided explanation in their testimonies that MPC must receive the proposed level of returns to compete for capital with other companies of similar risk. Mr. Haffey, for MPC, stated that MPC needs financial integrity to continue to provide safe, reliable service. He also stated that as a result of the divestiture, the Commission must more clearly treat the utility on a stand-alone basis as it would not be able to rely, even indirectly, on the financial soundness of the former total MPC corporation.

39. Ms. Senechal stated that the cost of long-term debt for the electric utility including the Pollution Control Revenue Bonds was an embedded debt cost of 6.46 percent. The gas utility

long-term debt cost was 7.13 percent. She also stated the preferred stock cost was 6.40 percent and the QUIPS preferred was 8.54 percent for all utilities. MCC concurred with the embedded debt and QUIPS preferred costs.

40. Ms. Senechal stated that over half of MPC's existing debt was Pollution Control Revenue Bonds. Those are tax-advantaged securities issued at a low interest rate and that particular type of security would not be available at this time. Due to those tax-advantaged securities, she stated that Mr. Hill's recommended 10.25 percent cost of capital was understated.

41. Mr. Benore, recommended in his direct testimony that the Commission allows a return on MPC's electric utility common stock equity of 13 percent and 13.5 percent for MPC's gas utility. He outlined his guiding principles and stated that MPC, like other investor owned companies, are owned and financed by investors who invest savings into its securities with the expectation of earning a fair, risk-adjusted return. He stated that the choice of investment was voluntary, investors have thousands of alternatives in which to invest and investors invest to earn as high a return as possible for a given level of risk. Mr. Benore stated that because of those guiding principles, MPC's electric and gas securities must offer sufficiently attractive returns so that investors will invest in MPC's securities. He stated that MPC's electric and gas utilities, which provide customers with indispensable energy services, must be sufficiently strong financially to cope with unforeseen events, and its securities must be attractive enough to access capital during adverse as well as more normal market conditions. He based his arguments on the U.S. Supreme Court decisions in the *Hope, Bluefield* and *Permian Basin* cases. He stated those cases noted that; 1) investors are entitled to the opportunity to earn a fair return on their investments in prudently managed companies, 2) a utility company should have an acceptable level of financial integrity so that investors have confidence in it, and 3) a company's securities should be sufficiently attractive to investors to assure that capital attraction can occur.

42. Mr. Benore, in his initial testimony, stated in his opening comments that electric and gas distribution common stock prices had under-performed other common stocks in recent years. He commented that in order to assure capital attraction at reasonable costs, it was necessary to increase returns so that reliable utility service to customers can occur in the future.

43. To support that assertion, Mr. Benore asked the Commission to consider four simple but crucial investment principles; 1) Investors assess future cash flows when making common stock investment decisions, 2) Investors expect higher returns for incurring higher risk and vice versa,

3) Investors of utility companies need to foresee an opportunity to earn fair, risk-adjusted returns before buying common stocks and 4) The "opportunity cost investment principle" states that investors will buy the most attractive investments in a given risk class, or across securities of different risk on a risk-adjusted basis and sell the least attractive.

44. Mr. Benore stated that short of stopping investment in electric stocks, investors had sent about as strong a signal as possible that the return prospects for electric stocks had not been competitive with other common stock investment alternatives. He stated that similar results were shown for the gas distribution stocks as well. He also stated that profitability was too low and needed to be increased by allowing higher returns on common stock equity to MPC's electric and gas utilities.

45. Mr. Benore proposed the theory that the Discounted Cash Flow (DCF), the Equity Risk Premium (ERP) and the Capital Asset Pricing Models (CAPM) only worked for regulatory purposes when the price-to-book ratio was not significantly different from 1.0. He stated that in light of his perception of increased risk of rising capital costs (inadequate allowed returns) and inability to attract capital, that strict reliance on theoretical models to determine the cost of common stock created the danger of over-quantification of a complex issue. He recommended that the Commission consider the results of the comparable earnings method, which was the most widely used test by regulators after the DCF test. Mr. Benore believed that investors had rejected past regulatory returns for electric and gas utilities as too low relative to returns offered by other investment alternatives on a risk-adjusted basis. This had negative long-term consequences for the ability of MPC's electric and gas utilities, and the comparable risk companies, to reliably raise capital and serve customers according to Mr. Benore.

46. Mr. Benore used four models for his estimates, three market-based models, DCF, ERP and CAPM and the fourth was the comparable earnings model.

47. Mr. Benore, in his initial testimony, used the DCF model and calculated a cost of common stock for MPC's electric utility of 11.0 percent for the Broad Criteria Group and 11.6 percent for the Narrow Criteria Group. He stated the result for MPC's gas utility using the DCF model the investor-market-return was 11.3 percent. In his rebuttal testimony, Mr. Benore calculated a 10.9 and 10.3 percent for the Broad and Narrow Criteria Groups respectively for the electric utility. Mr. Benore then "transformed" those returns to 13.4 and 11.4 percent for the Broad and Narrow Criteria Groups and 13.0 percent for the gas utility. Mr. Benore also

proposed that the flotation costs associated with stock issues would increase the amount needed for investor returns by 0.1 percent.

48. Mr. Benore stated the ERP test showed an equity risk premium for MPC's electric utility of 5.0 percentage points plus the yield on long-term government debt. He stated that the month before he prepared his testimony, the bond cost was 7.1 percent. This, Mr. Benore said, showed an investor-required-market-return of 12.1 percent or 12.2 percent adjusted for flotation costs. Mr. Benore stated that the necessary regulatory allowed return on common stock equity to provide investors with the prospect of an 12.1 percent return was 14.2 percent for the Broad Criteria Group and 13.0 percent for the Narrow Criteria Group. He calculated the MPC gas utility equity risk premium at 5.3 percent. He stated that with the yield on long-term Treasury Bonds of 7.1 percent, the investor required-market return was 12.4 percent, which necessitated a regulatory return of 14.1 percent and 14.2 percent after transformation and flotation costs.

49. Mr. Benore used four different CAPM versions to calculate a required market return by investors of 11.6 percent before flotation costs of 0.1 percent for MPC's electric Broad Criteria Group and 11.9 percent for the Narrow Criteria Group. For the gas utility, the CAPM investor required market return was 12.2 percent. With Mr. Benore's transformation, the CAPM would be 13.9 percent before flotation costs of 0.1 percent.

50. Mr. Benore also performed a comparable earnings analysis of the investor-expected-return on common equity for MPC's electric and gas utilities. That analysis showed a cost of common stock for MPC's electric Broad and Narrow Criteria Groups of 13.2 and 12.8 percent respectively. Mr. Benore stated that because those are book returns, there would be no need for transformation.

51. Mr. Benore explained that transformation was the process that determined the necessary regulatory book return so that investors would have an opportunity to earn their required market return. Mr. Benore commented that common sense and investment theory dictate that investors must receive fair compensation for the use of their capital, or comparable returns on a risk adjusted basis versus other investment opportunities. Mr. Benore stated that it was necessary that the regulatory return, which is a book return, provide investors with a reasonable opportunity to earn their required market return. Mr. Benore stated that was accomplished by the transformation of the standard DCF return, and the return from other market based models, into the necessary regulatory return.

52. Mr. Benore stated that common stock equity invested in by investors is reduced by the amount of issuance costs in the sale of new common stock. He stated that it is necessary to increase the return to investors so that the resulting earnings on the reduced investment represent fair return on the full amount of their investment. This necessary 0.1 percent "flotation adjustment" is based on flotation costs of about 2 percent.

53. Mr. Benore recommended to the Commission that, through his analysis, the four tests that he used showed a cost of common stock range of 13.1 to 14.2 percent before flotation costs for the Broad Criteria group with a mid-point of 13.7 percent. He stated, however, that the four tests showed a lower cost of common stock for the Narrow Criteria group, a range of 12.5 to 13.0 percent with a 12.8 percent mid-point. Based on his tests, Mr. Benore recommended a MPC electric utility cost of common stock at 13 percent in his original testimony and 12.75 percent in his rebuttal testimony. For MPC's gas utility, Mr. Benore's recommendation, after giving consideration to its relative financial risk, was 13.5 percent. He stated that those recommended returns would fulfill the financial integrity needs for MPC's electric and gas utilities.

54. Mr. Hill, representing MCC, organized his testimony into four sections; 1) the cost of capital standard as a measure of the return to be allowed for regulated industries and review the current economic environment in which the equity return estimate was made, 2) a review of MPC's requested capital structure, historical capital structure, as well as capital structures existing in the electric and gas utility industries and recommend capital structures appropriate for MPC's electrical transmission and distribution and gas distribution operations, 3) he evaluated the cost of equity capital using DCF analysis, CAPM, MEPR and MTB analysis to confirm and temper the results of the DCF analysis and 4) he commented on Mr. Benore's pre-filed testimony and pointed out theoretical and practical shortcomings contained in his testimony.

55. Mr. Hill estimated MPC's cost of equity for the electric utility's T&D operations to be in the range of 9.75 percent to 10.5 percent and for gas distribution operations to be in the range of 10.25 percent to 11.00 percent. Mr. Hill recommended a point-specific rate of return for MPC's electrical transmission and distribution operations of 10.25 percent and 10.75 percent for gas distribution operations. Mr. Hill stated that those returns and the aforementioned capital structure derived an overall rate of return for MPC's electric T&D operations of 8.14 percent and an overall return of 8.82 percent for MPC's gas distribution operations.

56. Mr. Hill stated that using his recommended capital structures and equity returns would afford MPC the opportunity to achieve a pre-tax interest coverage of 2.83 times for electric and 3.31 times for gas. According to Mr. Hill, the level of pre-tax interest coverage was virtually identical to or above the level the company has achieved historically. Mr. Hill said that with that level of interest coverage, MPC would be able to maintain its credit and attract capital as required in *Hope* and *Bluefield*.

57. Mr. Hill contended that the cost of capital served as a basis for the proper allowed rate of return for a regulated firm. He stated that the Supreme Court established as a guide to assessing the appropriate level of profitability for regulated operations, that investors in such firms to be given an opportunity to earn returns that are sufficient to attract capital and are comparable to returns investors would expect in the unregulated sector for assuming the same degree of risk. He went on to state that the *Hope* and *Bluefield* cases provided the seminal decisions. He stated though the criteria was restated in the *Permian Basin Area Rate Cases*, the Court also made it quite clear in *Hope*, that regulation did not guarantee profitability, and in *Permian Basin*, that while profitability was pertinent to setting adequate rates, that profitability did not exhaust the relevant considerations.

58. Mr. Hill stated that, as a starting point in the rate setting process, the cost of capital of a regulated firm represented the return investors could expect from other investments assuming no more and no less risk.

59. Mr. Hill then reviewed the economic environment because the cost of equity capital is expectational. He stated, in order to estimate the cost of capital, it was necessary to gauge investor expectations with regard to the relative risk and return of that firm, as well as that for the particular risk-class of investments in which that firm was classified.

60. Mr. Hill reasoned that, although there was a strong upward movement in interest rate levels during 1999 and early 2000, that movement had leveled off and the overall level of fixed-income capital costs continued to remain low by historical standards. Mr. Hill stated that a recent A.G. Edwards report indicated that market returns on gas utility stocks were well below historical earned returns and the median total return expected for a sample of 19 large and small gas distributors was approximately 9.5 percent. Many of those firms had significant unregulated operations and as a result had higher overall investment risk. A.G. Edwards return expectations for those integrated gas utilities was 9.8 percent. Mr. Hill stated that the data underscored the

fact that investor return requirements for a utility equity investment - even with the recent increases in interest rates - remained relatively low.

61. Mr. Hill stated another reason investors were willing to buy and hold stocks that offered relatively low returns was based on Moody's A rated utility bond yields from 1984 through October 2000. Those yields showed that interest rates and capital costs, even with the recent yield increases, remained low relative to the interest rate levels that had existed in the mid 1980s. Mr. Hill said that the data indicated that capital costs, even with the recent credit tightening by the Federal Reserve remained at relatively low levels and generally supported the efficacy of his capital costs.

62. Mr. Hill stated that overall, as inflation had remained calm, interest rates trended downward. The general downward direction had been interrupted by the Fed and by the investors' belief that falling interest rates would spur rapid economic growth. Mr. Hill went on to postulate that rapid economic growth had historically created unwanted inflation. He said investors anticipating that higher inflation and interest rates might be the result of rapid economic expansion reacted to the positive or negative economic news by bidding down debt prices and driving up interest rates.

63. Mr. Hill commented that single A rated utility debt yielded about 7.6 percent in 1999 and more recently had yielded about 8 percent. He stated that the cost rate increase was due primarily to investors' concerns about the continued strength of the U. S. economic expansion and the potential for increased inflation caused by that rapid level of growth.

64. Mr. Hill selected several utility groups to study the cost of equity capital for MPC's electric transmission and distribution (T&D) and gas distribution operations. Mr. Hill's studies of the current ratio of market price per share to book value per share for utility operations indicated that the equity costs he recommended are representative of the equity capital cost of electric T&D and gas utility operations. He stated that for the companies reported on in C.A. Turner's Utility Reports that the average market to book ratio ranged from 171 to 204 percent and the current earned equity return ranged from 10.5 to 13.5 percent. Further, he stated that for those utility industries, Value Line reported historical returns of approximately 11 percent and expected book equity returns from 2000 through 2005 as high as 13 percent.

65. That, Mr. Hill contended, showed investors were willing to provide a market price for utility companies that substantially exceeded the book value of those companies. That indicated

that the cost of equity capital (the investors' required return) for a utility investment was less than the return on book value that investors expected those companies to earn. Mr. Hill argued that it was reasonable to believe the market-based cost of capital for electric utilities would be below the 11 to 13 percent range of book equity returns. He stated that utility equity cost in the 10 to 11 percent range was reasonable, perhaps even conservative, and MPC's requested equity return of 13 to 13.5 percent was unrepresentative of the cost of equity capital.

66. Mr. Hill did not recommend the use of market-to-book ratios to set the cost of equity capital for MPC, but instead used a DCF analysis supplemented with three other equity estimation techniques. As a result of his analysis, Mr. Hill determined the cost of equity to be in the range of 9.75 to 11 percent for MPC's electric and gas utility operations. He used the market-to-book ratios as a check to reinforce his findings.

67. Mr. Hill stated the DCF, or Gordon model, points out that the market to book value ratio is greater than one when the ratio of the expected rate of return to the cost of capital is greater than one, equal to one when the ratio of the expected rate of return to the cost of capital is equal to one, less than one when the ratio of the expected rate of return to the cost of capital is less than one. He also stated that it was important to note that the relationship between market price and book value is not linear or a one-for-one relationship. Also, he pointed out that there are differences between a utility's book value and its rate base. He said it meant that even if a utility were allowed and expected to earn its cost of equity capital, the market price may not exactly equal book value.

68. Mr. Hill stated that Mr. Benore's logic was flawed because he incorrectly assumed that projected returns on book equity for utility companies are equivalent to investors' required returns. According to Mr. Hill, that was not correct. He said that investors could purchase an equity interest only by buying a share of common stock at the current market price, not at the current book value per share. Mr. Hill stated that when investors are paying market prices that substantially exceed book value, as they are for utility equities today, the DCF (or any other market-based analysis) continues to provide accurate estimates of the cost of equity. This is contrary to Mr. Benore's assertions. Mr. Hill said that cost of equity (the investors' required return) would be below the return on book value expected to be earned by the utilities.

69. Mr. Rosenberg, representing the Large Customer Group, also took exception to the proposed return on common equity proposed by MPC. He argued that the Narrow Criteria

sample group selected by Mr. Benore was made up of integrated electric utilities and reflected the typical risk and estimates the investor required return for an integrated utility. This sample, Mr. Rosenberg contends, was not comparable in risk to MPC, now an electric T&D utility. The integrated electric utilities' business risks are considerably higher than the risks now faced by MPC. Mr. Rosenberg recommended that the Commission recognize the greater business risk of integrated electric utilities and thus greater investment risk. He also asked the Commission to realize that the returns of the Narrow Criteria Group selected by Mr. Benore were overstated and should not be used to establish MPC's return on equity.

70. Mr. Benore, in rebuttal testimony, stated that there were major infirmities in the testimony of both Mr. Hill and Mr. Rosenberg. The most fundamental by Mr. Hill was: 1) recommending a regulatory return that would produce neither the growth rate nor the return that Mr. Benore believed investors require, and as a result investor expectations would not be fulfilled and problems attracting capital at reasonable costs would likely occur, 2) employing improper modeling for measuring investor expectations, which would also undermine MPC's electric and gas utilities ability to attract capital at reasonable costs, 3) ignoring the second most widely used test for determining the cost of commons stock by regulators, the comparable earnings model, which shows a much higher cost of common stock than recommended by Mr. Hill, 4) improperly assuming that the risk of MPC's electric and gas utilities would be the same as for his comparable companies, 5) failing to define financial integrity, which adds to the unreliability of his recommended investor required returns and 6) making two critical mistakes in his peer group comparisons to support his proposed capital structure.

71. Mr. Benore suggested in rebuttal that these infirmities caused Mr. Hill to materially understate the cost equity for MPC's electric and gas utilities and caused Mr. Hill to propose an inappropriate capital structure.

72. Mr. Benore stated that Mr. Rosenberg's testimony also made a number of assertions that were without substantiation. Mr. Benore said that Mr. Rosenberg was wrong in stating that: 1) Benore's Narrow Criteria list reflected the typical risk of integrated electric utilities, 2) that the Commission should allow a lower return than indicated for the Narrow Criteria Group of comparable companies, 3) that the Narrow Criteria Group results should not be used because of higher risk than for MPC's electric utility and 4) MPC's capital structure for this proceeding should be rejected.

73. Mr. Benore stated that Mr. Hill's return recommendations would dictate investor expectations rather than follow them, drive prices toward or to book value, cause investors to lose money, and repel rather than attract investor capital. Mr. Benore stressed that it was paramount that investors have an opportunity to earn fair market returns for the level of risk incurred, or as indicated by commons sense and financial theory, they would invest their capital in those companies that do provide them with reasonable returns for the amount of risk incurred.

74. The issue of flotation costs were again presented in this Docket, with Mr. Benore proposing an adjustment of 0.1 percent for flotation costs. The Commission has not allowed flotation costs in the past and there is no adequate reason presented in this Docket to change that practice. Allowing flotation costs would provide an annual recovery for all issuance costs of outstanding common equity regardless of whether these costs were actually incurred.

75. Mr. Benore went to some lengths to propose his theory of transformation of regulatory return to investor return. When asked if the theory had ever been approved in any commission orders anywhere, Mr. Benore was unable to provide any testimony, orders or regulatory commission orders that accepted his theory. The Commission questions the appropriateness of approving a methodology that has been denied by other Commissions in other states in the past. The request of MPC for the transformation methodology is not accepted. Disregarding the "transformation" adjustment, and the "flotation costs", the calculated returns on equity for both MPC and MCC are less than 1 percent apart.

76. The updated DCF analysis by Mr. Benore indicated a cost of common stock for MPC's electric utility of 10.9 percent for its Broad Criteria Group and 10.3 percent for its Narrow Criteria Group. For the gas utility, Mr. Benore estimated the DCF cost of common stock to be 10.9 percent. These percentages are exclusive of the "transformation" and "flotation" adjustments. The DCF analysis by MCC indicated a cost of common stock of 10.29 percent for electric and 10.57 for gas.

77. The ERP analysis by Mr. Benore showed a 12.1 percent cost of common stock for the electric utility and 12.4 percent for the gas utility. Again, these percentages ignore the "transformation" and "flotation" adjustments. Mr. Benore, when asked if there was a risk element in time stated there was a time risk. His calculations for ERP and CAPM used long term treasury's as the "risk free" rate. He did not make an adjustment for time risk in his proposals. MCC's risk free rate is 6.2 percent, MPC's risk-free rate is 7.1 percent, the difference being 0.9

percent. Adjusting Mr. Benore's ERP by the 0.9 percent results in a 11.2 and 11.5 percent cost of common equity for electric and gas utilities respectively. Again there is less than1 percent difference between Mr. Benore's calculation and that proposed by MCC.

78. The CAPM analysis by Mr. Benore's showed a required-market-return by investors of 11.6 percent before floatation costs for the Broad Criteria Group, 11.9 percent for the Narrow Criteria Group, and 12.4 for the gas utilities. MCC's CAPM analysis produced an average return of 10.6 percent for the electric utilities and 10.9 for the gas utilities. Adjusting for the difference in risk free rates reduces Mr. Benore's CAPM analysis to 10.7 percent for the Broad Criteria Group, 11.0 percent for the Narrow Criteria Group and 11.5 percent for the gas utilities.

79. Mr. Benore, in his Comparable Earnings Analysis (CEA), left out an important piece of data, that being the comparison of comparable earnings to the authorized rate of return of those utilities. Without that information, the CEA done by Mr. Benore allows no comparison of Regulatory Allowed Returns versus Comparable Earnings.

80. Mr. Haffey, when questioned by the Commission about his comments in prefiled testimony that as a result of divestiture, the Commission must more clearly treat the utility on a stand-alone basis, as it will no longer be able to rely, even indirectly on the financial soundness of the former MPC corporation and that his belief that the Commission relied either directly or indirectly on the soundness of the total corporation previously, Mr. Haffey stated that he would not be able to pick particular examples or specific clear, unambiguous proof of that.

81. The Commission requested a late filed exhibit providing specific citations to parts of any cost of capital orders where this Commission had relied on the financial soundness of the total corporation. The late filed exhibit by Mr. Haffey stated that capital structure had been presented on a utility only basis and as such, the orders did not portray whether or not the Commission relied on the financial soundness of the total corporation. Mr. Haffey's obvious attempt to mislead the Commission through innuendo will be ignored, but it is noted that MPC could not support Mr. Haffey's comment.

82. MPC was queried at length by the LCG as to whether MPC ever presented itself as a company with an inordinate amount of risk to any of its lenders, rating agencies, or shareholders. MPC stated that they would not represent the company as unusually or exceptionally risky. The Commission realizes that MPC in those presentations to lenders, credit agencies and shareholders, wanted to put its best foot forward in order to secure favorable borrowing rates and

credit ratings. But for ratemaking purposes, MPC is holding itself out as an unusually or exceptionally risky company that needs a much higher rate of return than has been granted in the past.

83. The Commission does not accept the reasoning of MPC that it is a much higher risk company that needs a much higher rate of return. Rather, the Commission concurs with the Large Customer Group and comments by Standard and Poor's that the sale of the generation facilities enhanced MPC's business risk profile and credit profile. The electric utility has risk exposure necessitating a slightly higher return than recommended by the Montana Consumer Counsel, but not to the level proposed by Mr. Benore. Therefore, the Commission determines that the authorized cost of common capital for the electric utility is 10.75 percent.

84. The gas utility no longer has greater risk exposure that the electric utility has due in part to the annual gas tracker allowing changes in commodity to be passed through to the consumers without going through a full rate case. The risk for any commodity cost fluctuations is greatly reduced by the gas tracker. Therefore, the gas utility authorized cost of capital should be adjusted to reflect that reduced risk, but still allow for the risk associated with the size of the stand-alone utility. The Commission agrees with the MCC that an authorized cost of common capital for the regulated gas utility of 10.75 percent is sufficient to allow for those risks and provide the necessary return.

85. The following is the authorized regulatory capital structure and associated costs for the regulated electric utility:

Type of Capital	**Amount**	**Percent Capitalization**	**Rate**	**Rate of Return**
Long Term Debt	$249,406	42.17%	6.46%	2.59%
QUIPS	48,815	7.86%	8.54%	0.67%
Preferred Stock	43,298	6.97%	6.40%	0.45%
Common Equity	279,424	43.00%	10.75%	4.62%
	$620,943	100.00%		8.46%

86. The following is the authorized regulatory capital structure and associated costs for the regulated gas utility:

Type of Capital	**Amount**	**Percent Capitalization**	**Rate**	**Rate of Return**
Long Term Debt	$82,361	40.17%	7.13%	2.86%
QUIPS	16,120	7.86%	8.54%	0.67%
Preferred Stock	14,298	6.97%	6.40%	0.45%
Common Equity	92,273	45.00%	10.75%	4.84%
	$205,052	100.00%		8.82%

Rate Base

87. Based on all the adjustments, the Commission approves a rate base of $579,963,614 for the regulated electric utility. The Commission also approves a rate base of $255,983,533 for the regulated gas utility.

Traditional vs. Optional Filing Rules

88. In March of 1992 the Commission adopted optional filing rules (OFR) for electric, gas, water and sewer utilities. See A.R.M. 38.5.601 to 38.5.611. These rules contained a sunset provision that stated:

> "The rules in this subchapter are of an experimental nature and are intended to be of limited duration. The rules in this sub-chapter are repealed 96 months after publication of their notice of adoption."

89. After adoption of these rules, only three utility companies elected to proceed under the optional filing rules; MPC, Energy West and Mountain Water. In terms of interest expressed by utility companies, the OFRs were not as popular as one might have expected prior to the adoption of the new rules.

90. The new rules allowed the use of year-end rate base, year-end customer counts, annualization of known changes in revenues occurring during the test year, and costs which were not adjusted for known changes were increased by .45 times the consumer price index.

91. At the time MPC made its filing in Docket No. D2000.8.113 in August of 2000, the optional filing rules (OFR) had expired. According to Mr. Clark, MPC acknowledged the expiration of the OFR. Mr. Haffey stated that the optional filing rules had expired at page 2, line 18 of his direct testimony.

92. Mr. Haffey argued that to revert to traditional rules after basing rates on the optional filing rules since 1992 would be a step backward for regulation. He stated that the use of the OFR resulted in an appropriate matching of revenues and expenses by using year-end rate base and better helped the utility match its actual cost of service with rates by using an historical test year.

93. Mr. Clark for MCC stated that prior to the adoption of the OFRs, the Commission consistently used average rate base. The basis for using average rate base was to match the relationship between operating income and rate base. He noted that the OFRs were designed as an experiment that attempted to provide a match between operating income and rate base, but in his opinion that goal was never reached.

94. In the rate cases filed by MPC under the OFRs, MPC and MCC consistently disagreed about the proper number of customers at year-end as well as the correct calculation of the attrition adjustment.

95. Mr. Clark did not agree that year-end customer count was a true match for year-end plant. Plant additions are typically designed to accommodate growth in both the load of existing customers as well as the load of future customers. That was because economies of scale and the need for reserves are such that it is economical to build facilities now that will accommodate expected future growth.

96. Mr. Clark argued that there are at least two serious flaws in any attempt to "match" year-end rate base with operating income at a single point in time: 1) adjustments to revenues and expenses which attempt to restate operating income to the level that would be produced if the year-end level of operations had continued for a full year are necessarily speculative, and 2) even if the adjustments are not speculative, the approach under OFR fixes on conditions as of a single point in time which most certainly will not be representative of the longer-term relationships such as those that can be measured over an entire year.

97. In rebuttal testimony, Mr. Haffey stated that the OFRs move rate base, revenues and costs closer in time to when rates become effective. Mr. Haffey did not agree with Mr. Clark that MPC's revenue requirement must be based on traditional filing rules due to the expiration of the OFRs. The Commission's minimum filing requirements require the utility to file its application based on average rate base and a historical test year. After filing that information, a utility may

then present testimony based on OFRs or other methodologies or adjustments. The Commission can approve the alternative approaches if they are found to be acceptable.

98. Mr. Haffey went on to state that MPC has had rates based on the OFRs for eight years without a public outcry that the rates were unjust and unreasonable.

99. In evaluating this issue it is instructive to examine Mr. Haffey's claims about lack of public outcry during the eight years the OFRs have been used. In Docket No. D96.2.22, MPC initially requested a gas increase of $4.8 million. The Company settled that case for an increase of $935,000. SB 390 contained a rate moratorium which prohibited electric rate increases for four years for electric supply and two years for distribution and transmission. All of these elements go a long way to explaining why there has not been public outcry about rates resulting from the OFRs.

100. The environment today is far different that it was in 1992 when the OFRs were adopted. Today, there is no longer a vertically integrated gas or electric utility in the case of MPC. Gas supplies come from a series of contracts whose costs have skyrocketed. The Commission approved an interim gas tracking increase of $18.8 million in January of this year. Electric customers will likely face sharply higher supply costs at the end of the transition period. In this environment, it does not make sense to continue the application of the OFRs.

101. After reviewing this issue, it is clear that the OFRs did not result in an improved matching of rate base, revenues and expenses. Since the OFRs were experimental, and have now expired, the current case should be determined using the traditional filing rules. MPC's request to use the OFRs in this case is denied.

SAS Adjustment

102. MPC had been accounting for its corporate offices and equipment under the subsidiary Montana Power Services Company. These shared administrative service (SAS) costs were shared among all of the Company's operating units based on both occupancy and by using a three-factor allocation for space that benefited all units, such as corporate offices. The buildings were removed from rate base and the utility has been paying rent for those facilities. Anticipating divestiture of all non-utility business units, the buildings were reassigned based on use.

103. Mr. Clark, representing MCC, explained that he did not agree with MPC's proposal regarding SAS plant. Historically, the SAS plant and expenses were used for both regulated and non-regulated entities under the MPC umbrella. The non-regulated businesses needed, and utilized, a portion of these facilities and costs. Mr. Clark stated that MPC requested that the bulk of those costs be reassigned to the T&D functions of both utilities. According to MCC, the proposal was made not because the regulated utilities had any additional need, or use, for these facilities, but rather, because the non-regulated entities are being divested. Mr. Clark said that there was no basis to assume that, simply because the non-regulated entities were being divested, the regulated utilities suddenly required additional SAS related plant and related costs in order to function as they had prior to the divestiture. Mr. Clark stated that MPC made business decisions to sell those non-regulated entities and there had never been any understanding between MPC, its ratepayers and its regulators that the ratepayers would act as a "backstop" by absorbing any and all costs that MPC was not able to sell or curtail as a result of those decisions.

104. Mr. Haffey stated that the adjustment as proposed by Mr. Clark would disallow recovery of all of the costs of administrative buildings and associated equipment in Butte. The buildings and equipment included in the Company's filing are needed to manage utility operations and are occupied by utility personnel. In response to Data Request MPC-2, Mr. Clark stated that it was not his intention to provide zero allowance to the utilities for general office plant in Butte. It was Mr. Clark's intent to provide the utilities with the same level of plant and expenses that they were responsible for prior to the divestiture of the unregulated subsidiaries. Mr. Haffey stated that with the divestiture and the resulting separation of the facilities, it was no longer necessary to keep the facilities in a separate business unit. As such, under MPC's proposal, the three buildings and associated equipment that were the responsibility of the utility would be moved into rate base and the rental expense previously reflected in rates would be eliminated. According to Mr. Haffey, that would assure that ratepayers only pay those costs that are necessary to provide utility service.

105. MPC, in its initial brief, argued that it made a change to the way it accounted for its corporate buildings and equipment in this Docket. Previously MPC had located the property in a separate company called the MPC Services Company. That company leased property to the various business units based on occupancy and a three-factor method. Because of the pending sale to Northwestern Corporation, MPC transferred the property out of MPC Services into the

utility rate base. MPC disagreed that an adjustment should be made. MPC asked to include in its rates only the costs of the buildings used to provide utility functions.

106. In MCC's initial brief it was noted that Mr. Clark admitted his proposal to reverse MPC's adjustment was incorrect. He was of the opinion that the amounts shown in MPC's filing were related only to the former SAS plant that had been the responsibility of the divested unregulated subsidiaries. Mr. Clark stated that MPC was not correct in saying that plant that was formerly the cost responsibility of the divested, non-regulated subsidiaries should be included in the revenue requirements of the electric and gas utilities. In response to MCC-237(c), MPC indicated that prior to the divestiture, the electric utility was responsible for 37.55 percent of the total costs of the buildings, and the gas utility was responsible for 15.51 percent of the costs. The response also included the comment that the allocations to the utilities "would be higher going forward" as a result of the divestiture. It was this increase "going forward" that MCC opposed.

107. MPC, in its reply brief, stated that MCC-237, which Mr. Clark used for his adjustment calculations, did not have the Hennessey building in it; therefore, MCC's calculations were wrong. MPC stated that it included only the buildings and related expenses that are needed to provide energy services. MPC also stated that those are reasonable expenses and MCC's attempt to label a portion of these expenses as unregulated was incorrect and unfounded.

108. In its reply brief, MCC stated that MPC, despite its attempt at favorable characterization, MPC did more than "simply make a change to the way it accounts for corporate buildings and equipment." According to MCC, MPC stated that it "is asking to include in its rates only the cost of the buildings used to serve utility functions," when in fact some of those costs were not included prior to its decision to divest its utility business. The electric and gas ratepayers should be responsible for no more plant and related expenses than they were prior to divestiture.

109. The Commission concurs with MCC with regard to SAS plant. The ratepayers are not a “backstop” absorbing any and all costs that MPC is not able to sell or curtail as a result of MPC's decision to divest. MPC has changed its methodology of accounting for SAS in anticipation of divestiture. MPC, in 1998, transferred ownership of assets that benefited the corporation as a whole to Montana Power Services Company. MPC is now arguing that, two years later, that due to divestiture, an event yet to happen, they want to change methodology again. This is not good accounting practice and violates the consistency principle. Divestiture may happen, but well

over a year after the filing of this rate case and is outside the scope that the traditional rules allow.

110. MCC, in data request MCC-237, requested the dollar breakdown of SAS plant for the General Office, Thornton Building, Energy Building and Hennessey Building. MPC failed to provide the dollar amount of SAS for the Hennessey building as requested in MCC-237. MPC did reconcile to the dollar amount given by Mr. Clark as total SAS plant but that figure did not include the Hennessey building. Mr. Clark used that information provided by MPC to calculate his adjustment.

111. MPC's adjustments to the rebuttal testimony are greater than the corrected amounts proposed by Mr. Clark. The Commission accepts MPC's revenue impact amounts. The impact is less than if the status quo of renting and allocating the facilities was maintained. Ratepayers should not bear the burden of costs associated with the change in methodology.

Incentive Compensation

112. According to Mr. Haffey, incentive compensation must be considered as part of the employees' total compensation package, just as benefits and salaries are considered and included in rates. Mr. Haffey stated that MPC had increased its base pay wages conservatively, relative to all benchmarks, over the last few years to change the way that compensation is received.

113. Mr. Haffey commented that customers benefit by incentive compensation because it is offset by smaller increases in base wages and they also benefit because incentive pay causes more efficient service. That is, the cash incentive payments are made only if measurable value is produced. Rates and cost of service are lower.

114. Mr. Clark proposed to remove incentive wages from the test year revenue requirement for the electric and gas utilities. In Docket No. D99.8.176, Mr. Clark proposed a similar adjustment to the gas utility's revenue requirement. In that Docket, MPC was unable to demonstrate any cost savings that were flowing to ratepayers as a result of the incentive wage programs. In the current case, Mr. Haffey provided testimony that attempts to support the inclusion of these costs, but according to Mr. Clark, there was no demonstration that there had been concomitant cost savings that would justify the incentive wages in the test year revenue requirements. Mr. Clark's adjustments would reduce electric expenses by $1,854,120 and gas expenses by $921,358.

Those amounts were based on the percentage of the incentive wages as compared to total labor costs included in Docket No. D99.8.176.

115. Mr. Haffey stated the standard for recovering the costs of doing business in rates is based upon those costs being reasonable and prudent. He said Mr. Clark did not suggest that MPC's compensation expense, which included incentive compensation, was unreasonable or imprudent, but rather Mr. Clark created a new standard that requires MPC to demonstrate cost savings before it may recover its compensation expense.

116. Mr. Haffey also stated that cost reduction was not the primary reason for providing incentive compensation. While managing costs was certainly an important goal of the incentive compensation plan design, the reasons for implementing incentive compensation were much broader. Incentive compensation created a mechanism to communicate what was important, focused behaviors and drove business results. Without an incentive compensation component to the total pay package, compensation levels would become non-competitive.

117. Mr. Richard Meischeid II, a principal of Towers Perrin, provided testimony on incentive compensation programs. Towers Perrin made several conclusions after reviewing MPC's compensation programs: 1) MPC's total compensation approach combining salary and variable pay was an effective approach to recognizing and rewarding performance, 2) The use of incentive plans was consistent with the practices of other utilities, 3) MPC's incentive plans for executives and non-executive employees were effectively designed and represented a balance of customer and shareholder interests and 4) without an annual incentive plan, MPC compensation levels would fall below competitive norms.

118. In its initial brief, MPC stated that it had changed the way that it compensated its employees. Instead of a compensation package that ignored the goals of the company, MPC paid a base compensation and accompanied that base level with incentive compensation when the employees achieved certain goals. MPC stated that cost savings are not the regulatory standard. MPC said that tying compensation opportunities to business results creates an environment where it is in the employees' interest to behave consistently with the goals of the employer. MPC said it did not agree that it was necessary to prove that incentive compensation had resulted in cost savings but said it had demonstrated cost savings. MPC stated that if incentive compensation were not approved, the company would be forced to return to traditional base pay

compensation, resulting in inefficient use of the utility's assets, which would not be in the customers or shareholders best interest.

119. MCC, in its initial brief, proposed to disallow the incentive wages in their entirety. MCC's argument was that incentive wages were supposed to be paid when cost savings were obtained. Absent the cost savings, the incentive wages ought not to be paid. MCC stated that contrary to MPC's assertion that it was not necessary to prove that incentive compensation had resulted in cost savings, that standard was established in Docket D99.8.176 and again in this case. MCC stated that MPC had failed to demonstrate a direct connection between any verifiable cost savings in the revenue requirements and the level of incentive wages that were included in the revenue requirements.

120. MPC, in rebuttal, stated the company provided support explaining how each of the utility departments had demonstrated improvement in Data Response MCC-195 and in Mr. Haffey's rebuttal testimony.

121. MCC, in its rebuttal testimony, stated that if incentive wages were being paid in order to take the total salary and wage scale of MPC employees up to a particular standard, regardless of cost performance, they were not incentive wages and should not be treated as such.

122. MCC's arguments certainly have merit, that compensation given to increase the total salary and wage scale up to a particular standard, regardless of cost performance, are not incentive wages and should not be treated as such. Equally valid are MPC's arguments that compensation paid when employees achieve certain goals encourage employees to strive harder to reach those goals. MPC is incorrect in its assumption that demonstrated cost savings are not necessary for their incentive compensation plan. In Docket 95.3.6, Accounting Order No. 5835b, the Commission, when authorizing accounting deferral for costs and benefits resulting from a workforce reduction, that the amount is expected to be more than offset by corresponding deferred and current period benefits, so that when rate treatment is requested, an annual net revenue reduction requirement will result. However, Commission is hesitant to micromanage MPC's compensation plan, and disallows MCC's suggested adjustment, with the understanding, that in future rate cases, MPC shall demonstrate that incentive compensation is based on reasonable company goals which provide measurable benefits to its utility customers.

ORCOM Development Cost Adjustment

123. The ORCOM Billing System is a billing system implemented by MPC to solve two major problems: Y2K and unbundled billing. The previous legacy system installed in 1988 was not Y2K compliant nor was the legacy system able to support unbundled billing.

124. MPC proposed to amortize the development costs over three years. MCC contended that the ORCOM system was scheduled to be implemented in 2 releases and because one release was not implemented, one-half of the development costs should not be included in revenue requirement computations.

125. MPC, in its initial brief, stated that the ORCOM system did not serve any non-regulated businesses nor was it implemented in two releases.

126. MCC, in its initial brief, stated that MPC indicated that the system was supposed to be installed in two releases and since only the first phase was implemented, only one half of the development costs should be allowed. MCC proposes to eliminate one half the costs of development from MPC's revenue request. MCC accepted both the statements that the ORCOM system "does not serve any non-regulated entities" and that the ORCOM system was "not implemented in two releases." MCC stressed that neither undermined Mr. Clark's original proposal, that the ORCOM system was "not implemented in two releases" did not equate to having one release accomplishing all of the tasks for which the originally contemplated two releases were planned. Mr. Clark's position was that the impending sale of the transmission and distribution utilities caused the cancellation of the second release

127. MPC, in its rebuttal brief, stated that the ORCOM system was MPC's utility billing system. The system was never intended to be used by MPC's unregulated businesses nor to be released in two releases. MPC stated that Mr. Clark was simply wrong in making the proposal.

128. MCC, in its rebuttal brief, stated that if the ORCOM system was not originally planned for two releases with the second cancelled, this adjustment should not be made.

129. The Commission concurs with MPC and disallows MCC's proposed ORCOM system adjustment. The ORCOM system is for use in the regulated utility, was released in one release, was intended to be released in one release, and MCC offered no definitive proof that it was to be offered in two releases.

AMR Savings Adjustment

130. MPC installed a new Automated Meter Reading (AMR) system that was completed in May 1999. Since the AMR system is being leased, costs for the system are included in the case as an expense versus being included in rate base. The AMR system has reduced the costs of meter reading primarily as a result of reduced labor expense.

131. Mr. Clark proposed an adjustment to recognize a full year of savings that result from the full implementation of the AMR system. In MPC's filing, the Company included an annualization adjustment to reflect a full year of the costs associated with the AMR. The resulting annualized cost savings for the AMR system had not been similarly reflected in the Company's filing. Mr. Clark stated that the Company had included savings "since realized" and costs on an annualized basis. His adjustment attempted to provide a better match between savings and costs. He reversed MPC's test period adjustment to A&G expense. For the electric utility, the adjustment decreased A&G expense by ($140,034). For the gas utility, the adjustment decreased A&G expense by ($281,154.)

132. MPC stated that MCC proposed the adjustment because the annualized cost savings had not been fully reflected in the filing. MPC did not agree. MPC stated that the majority of savings resulting from the AMR system was reduced labor costs. The reduced labor costs were included in the test period in this filing on an annualized basis and the other than labor savings had been realized since the start of the system in January 1998. MPC stated that the AMR system was virtually complete by December 1998 and there were only a few installations left to be made in 1999. MPC stated the MCC adjustment caused a mismatch because it allowed most of the savings to be included in the filing while MCC removed all of the costs.

133. MCC stated the adjustment was necessary because the Company had annualized the costs of the AMR System but failed to provide the corresponding and necessary match between costs and savings. MCC suggested two solutions to the mismatch problem inherent in MPC's proposal. One was to annualize the cost savings associated with the AMR system so that the savings would be reflected in the test year as if they were being realized since January 1, 1999. The other was to reverse MPC's proposed annualization of the costs so the test year reflected the costs and the savings on the same basis. Since the annualization of the cost savings was not available in the record, MCC proposed the latter alternative.

134. MPC said that MCC proposed to remove all of the costs of the AMR because MCC alleged that all the savings from the system had not been included in the revenue requirement. MPC contended that the savings that were not included were negligible and virtually all the savings were included.

135. MCC did not agree with MPC's contention that the system was virtually complete by December 1998 and that the assertion by MPC was at odds with MPC's own filing. MCC cited MPC's gas utility statement G page 7 of 49. The notes to that statement indicated that costs have been annualized by MPC while savings have not. MCC also took exception to MPC's assertion that Mr. Clark's proposed adjustment would remove "all the costs" associated with the AMR system. MCC stated that the adjustment would reverse an adjustment originally proposed by MPC to annualize the actual incurred costs during the test year. MCC proposed to leave the costs unadjusted, leaving the test year with the savings that occurred during the year and the costs that were incurred during the year. MCC also commented that for the first time, MPC alleged that the savings have effectively already been annualized in the labor adjustment.

136. MPC made the labor adjustment to reflect cost savings in labor from the first of the year for test year calculations. They proposed the same adjustment for AMR costs because the lease costs for the system changed as the system was completed. Commission agrees that those additional lease costs need to be reflected to more accurately ascertain the known and measurable costs and savings. The Commission disallows MCC's proposed adjustment.

Regulatory Expense Adjustment

137. Mr. Clark, representing the MCC, noted that for both the electric and gas utilities, MPC proposed to include regulatory expenses in the test year at a level equal to the average of the costs incurred over the four year period 1996 through 1999. Mr. Clark did not believe that MPC’s proposal is appropriate in this case for either utility.

138. Mr. Clark said that for the gas utility, the four-year period used by MPC reflected years during which gas production was being deregulated and the costs incurred in those years were not indicative of the future. Mr. Clark proposed to use the average of the two years, 1998 and 1999, to derive a representative level of regulatory expense for the gas utility. Mr. Clark recommended a test year level of regulatory expense of $90,107, $30,086 lower than MPC proposed.

139. Mr. Clark stated that for the electric utility, the four-year period 1996 through 1999 was a period where the deregulation and subsequent divestiture of the generation assets was being contested. To the extent that a portion of the historical costs was related to the generation function, those costs should not now be attributed to the transmission and distribution functions. He proposed to remove one-third of the average costs, i.e. $139,901, from MPC's four-year average of $417,272. As a result, he allowed two-thirds of the historical costs as being related to the transmission and distribution functions.

140. Mr. Strizic, from MPC, stated that Mr. Clark proposed to use a two-year average for the gas utility instead of the four-year average because Mr. Clark felt the last four years were not indicative of the future. MPC stated that Mr. Clark provided no support or explanation for his contention other than the last four years represented deregulation of gas production. Mr. Strizic stated only 1998 expense varied significantly from the other years in the four-year average and 1999 should be lower than the other three years due to a minimum level of regulatory activity during that year. MPC stated that was the exact reason a four-year average should be used to adjust such an expense. A four-year average was designed to normalize the yearly levels of expense and portray a realistic test period level of expense.

141. The four-year average had been supported by Mr. Clark and approved by this Commission in the past. Mr. Clark did not provided any convincing testimony to change the approved method of calculating test period regulatory expense and his proposed adjustment for the gas utility is rejected.

142. Mr. Clark's proposal for the electric utility was to remove the generation function from the test period numbers. Mr. Clark did not inquire as to whether or not generation was removed from the adjustment. In fact, generation had been removed and the regulatory expense adjustment was based on a four-year average of just transmission and distribution expense. Mr. Clark's proposed adjustment for the electric utility is rejected because he would be removing generation twice.

Liability Insurance Adjustment

143. The MCC proposed a reduction in electric utility expense of $15,720 and a reduction in gas utility expense of $58,333. This was the premium increase in Liability Insurance expense

above the 1999 liability premium levels. Mr. Strizic explained that property and liability premiums were adjusted for changes to the premiums that occur during the test period.

144. Mr. Clark proposed to remove the adjustment that MPC proposed to increase liability insurance above the actual 1999 amount. Absent substantiation of the Company's claim, Mr. Clark proposed to reverse MPC's adjustment.

145. Mr. Clark stated that MPC did not support the adjustment in its responses to data requests. Mr. Clark stated that MCC was not able to track the invoices to the test year proposals by MPC and if MPC were able to provide the invoices to support the Company's claim then MCC would withdraw its objection.

146. Mr. Strizic stated that Statement G page 14 (electric) and page 12 (gas) provide the test period amounts by policy. This was the same support MPC has provided to Mr. Clark for at least the last 10 years. Mr. Strizic stated that the invoices were included in the workpapers in the rebuttal filing.

147. At the hearing in this case, MCC did not cross-examine Mr. Strizic on the issue of liability insurance. In its review of this issue, Staff examined the workpapers and invoices provided by MPC in its rebuttal testimony. The review by staff found that the adjustments to liability insurance were fully supported by the workpapers and invoices. Therefore, the Commission accepts the adjustment for known changes to liability insurance proposed by MPC.

Montana Resources, Inc. Adjustment - Electric Only

148. Ms. Hansen for MPC also introduced a large new adjustment to reflect the loss of a major contract customer Montana Resources, Inc. (MRI). The normalized billing statistics were revised to reduce the load of Montana Resources Inc. to a minimum level of maintenance. This is in response to the customer announcing a shut down of its Butte facility. This adjustment represents a revenue requirement increase of approximately $2.7 million.

Storage Gas Sale Adjustment - Gas Only

149. MPC included in its calculation of gas utility rate base, the sales of storage plant that had occurred in 1999. Three sales were made from storage gas in 1999, one of which was included in rates in Docket D99.8.176. MPC included the other two as part of this filing and requested

that the costs of a compressor required to make the sale and not installed until late 2000, also be included as an offset to the sale.

150. MCC contended that MPC availed itself of the opportunity to sell certain storage gas volumes at a time when gas prices were high. That gas had previously been used, not as a part of supply, but to provide storage pressure for withdrawals.

151. In rebuttal testimony, MPC stated that the compressor was not installed until late 2000 and recommended that it not be used in the test year rate base.

152. MPC in its rebuttal brief stated that the sale of 1999 storage gas reduced revenue requirement $991,415.

153. MPC sold storage gas with an inventory value of $4,287,703 in 2000. The gross proceeds from the sale totaled $14,618,352. MPC asked the Commission to ignore the sale as it was not a "major" change to rate base and was a change to rate base beyond the test year. The basis of this claim, according to MPC was that the net proceeds after the sale would only be $517,967. MPC is also raising the issue of matching, not whether a reduction in the revenue requirement exists.

154. There was a $4,287,703 reduction in rate base and a 10.8% change in the inventory of cushion gas. MPC Docket No. 90.6.39 Order No. 5484k stated that a change of 8 percent in plant was accepted by the Commission, but 3 percent in itself as an effect to plant was not. The order specifically referred to plant, not to total rate base and was in the course of ordinary expansion. If this was applied to the present proposed adjustment by Mr. Clark, the inventory cost of cushion gas sales as compared to the total inventory cost of cushion gas would be 10.8% of cushion gas. That would be in excess of the 8% "bright line" test of materiality allowed in Docket 90.6.39 and therefore a material change. The transaction was not a normal recurring event so MPC's argument about matching would not apply. After hedging costs and taxes, there would be a $6,107,231 net proceeds before the capital investments of $5,589,264 that were needed to make the sale possible. The net after reduction of inventory, hedging costs, taxes and capital investments would be $517,967.

155. However, Administrative Rules of Montana 38.5.106 states that no adjustments shall be permitted unless based on changes in facilities, operations, or costs which are known with certainty and measurable with reasonable accuracy at the time of the filing. ARM 38.5.106 also states that no adjustment will be entertained unless it will become effective within 12 months of

the last month of the test period. MPC filed its rate case on August 11, 2000. The storage gas sales in question took place in December of 2000. MPC, at the time of filing, would not have been able to know with certainty and measurability with reasonable accuracy, the revenues and costs associated with the sale. The sales in question were consummated in December of 2000, with much of the equipment necessary for the sale put into production in 2001, outside of the 12 month test year cut off. The Commission will allow the storage gas sale to be excluded from this rate case, with the understanding that those storage gas sales will be addressed in the next rate filing.

Other Issues

156. In Order No. 5865d, Docket No. D95.9.128, Commissioner Anderson wrote an opinion which raised policy issues related to performance-based regulation and asked that they be addressed in future proceedings. They were not.

157. Now that MPC has divested its generation and has become a transmission and distribution utility, these and other issues are even more important.

158. The Commission now requires that these policy issues be addressed in MPC's next rate filing. Among them are the following;

> In a T&D utility how can the interests of the utility and its customers best be aligned?
>
> What are the merits of fixed vs. variable charges? What priced signals are conveyed with either approach? What are the incentives to utility and customers under either approach? Should utility profits be linked to or dependent on the level of sales? Are T&D costs fixed over the short or long terms?
>
> What are the best policies for distributed generation? Are there inter-connection barriers and how can they be eliminated? What should be the back-up and standby charges? Is the location (side of the meter) of distributed generation important and why? Is ownership of distributed generation important? Are Montana's net metering policies adequate? What are the environmental characteristics of different DG technologies and how can they be considered in utility policies?
>
> What are the best policies for demand-side management? How can customer load be responsive to system conditions and varying prices? How can economical incentives for baseload DSM be applied? How can regulatory barriers to DSM be eliminated?
>
> How much reliability is the right amount? How can large-scale problems (generation adequacy, transmission links, ancillary services) be distinguished from local (mostly distribution) reliability issues? What are the best distribution system reliability standards? What are different ways to achieve reliability? How can the contributions to

reliability of energy efficiency be incorporated into distribution system planning? What is the best way to select least-cost reliability strategies and investments.

What are the merits of performance-based regulation, as opposed to rate base, rate-of-return regulation? What are the merits of different forms of PBR, such as price caps, revenue caps, and per-customer revenue caps? What other indices, such as reliability and service quality, should be considered in PBR?

What are the best line extension policies? Should customers be responsible for distribution costs imposed on the system?

How can the general body of rate payers be protected from the coming and going of large loads? What are the merits of strategies such as exit fees, bonds and hold-harmless rate designs and adjustments?

How can the high cost areas of a distribution system be identified? What strategies should be pursued to address high-cost areas, for example least-cost investments, deaveraged rates, and/or credits?

What is the best way to accomplish Common Sense Distribution Planning, which results in the most economical long-term expansion, upgrades, congestion management, and customer service? What process should be used?

159. The Commission encourages MPC to address these and other issues through a collaborative process prior to the next rate filing.

CONCLUSIONS OF LAW

1. Montana Power Company furnishes electric and gas service for consumers in the State of Montana, and is a “public utility” under regulatory jurisdiction of the Montana Public Service Commission. Section 69-3-101, MCA.

2. The Montana Public Service Commission properly exercises jurisdiction over Montana Power Company’s rates and operations. Section 69-3-102, MCA, and Title 69, Chapter 3, Part 3, MCA.

3. The Montana Public Service Commission has provided adequate public notice of all proceedings, and an opportunity to be heard to all interested parties in this Docket. Sections 69-3-303, 69-3-104, MCA, and Title 2, Chapter 4, MCA.

4. The rate levels approved herein are just, reasonable, and not unjustly discriminatory. Sections 69-3-330 and 69-3-201, MCA.

ORDER

1. Montana Power Company is authorized an increase in annual Montana jurisdictional electric revenues of $16,006,589. This increase is in lieu of and not in addition to Interim Order No. 6271b. The increased rates shall be on a uniform percentage basis.

2. Montana Power Company is authorized an increase in annual Montana jurisdictional natural gas revenues of $4,268,652. This increase is less than the $5,277,978 granted in Interim Order No. 6271b. The difference shall be rebated to customers with interest of 11.25 percent. The increase of $4,268,652 shall be on a uniform percentage basis.

3. Montana Power Company is ordered to file compliance tariffs pursuant to this Order.

4. Montana Power Company is ordered to comply with any and all directives of the Commission as described in the body of this Order.

5. The effective date of this Order is May 8, 2001.

DONE AND DATED THIS 8th day of May, 2001 by a vote of 3 - 2 .

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

The original signed copy of this order is on file at the Commission's office.

GARY FELAND, Chairman (dissent)

JAY STOVALL, Vice Chairman

BOB ANDERSON, Commissioner

MATT BRAINARD, Commissioner (dissent)

BOB ROWE, Commissioner

ATTEST:

Rhonda J. Simmons
Commission Secretary

(SEAL)

NOTE: Any interested party may request the Commission to reconsider this decision. A motion to reconsider must be filed within ten (10) days. <u>See</u> 38.2.4806, ARM.

CERTIFICATE OF SERVICE

I hereby certify that a copy of a FINAL ORDER, ORDER NO. 6271c , issued in D2000.8.113 in the matter of Montana Power Company - Application for Authority to Change Rates for Electric and Natural Gas Service dated May 8, 2001 has today been served on all parties listed on the Commission's most recent service list, updated 1/24/01, by mailing a copy thereof to each party by first class mail, postage prepaid.

Date: May 9, 2001

Rachel Thompson
For The Commission

Intervenors:

- American Association of Retired Persons (AARP)
- Commercial Energy of Montana, Inc.
- Colstrip Energy Limited Partnership (CELP)
- Cut Bank Gas Company
- District XI Human Resource Council (HRC)
- Jefferson Energy Trading, LLC (Jetco)
- Large Customer Group
- Montana Consumer Counsel
- Montana Department of Natural Resources and Conservation
- Yellowstone Energy Limited Partnership (YELP)